Deregulation of the Electric Power Industry: The Impact of Transmission on Market Imperfections

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Abstract

In a framework where deregulating the electric power market is an objective to be achieved, this thesis investigates how the transmission rules chosen by the regulator to deregulate this market will shape the incentives given to the market players and influence their market power. To study this influence, it is challenging the perfect market assumptions and examining how physical and financial rights on the transmission grid will affect the efficiency of two of the formal components of the market for electric power, the market for energy itself and the market for transmission.

It is first shown how transmission constraints can create locational market power in network economies, and how loop flow increases dramatically this problem in electric power networks. Classical oligopolistic competition models are investigated. It suggests that in a Bertrand competition framework, which seemed more adequate than a Cournot competition for describing short-term behavior, tacit collusion can take place. This is further encouraged by transmission constraints and short-term spot markets. Moreover, financial rights, used for hedging against transmission cost or for funding the grid expansion, can create long term and short term detrimental incentives especially, but not exclusively, if their revenue depends on the ex-post prices or flows on the market.

In the second part, a number of general policy recommendations are discussed and it is shown, from an analytical point of view, how they could reduce some of the imperfections described in the first part. It is shown how the duration of the contracts between sellers and buyers has a direct effect on sustainability of tacit collusion and how, under certain general conditions, tacit collusion is not sustainable if this duration is above seven years. Most importantly, it will be proposed that financial instruments for grid expansion that yields a revenue depending on the ex-ante characteristics of the market can be effective to reduce the general problem of locational market power. A simulation of a 24-bus system is used to illustrate this last point as well as to show how loop flows create locational market power.

The implementation of the policy recommendations that were analytically found useful is discussed. They are compared to other methods to reduce market power, and their implementation is shown to be realistic if a centralized body is to plan the investments in the transmission grid. Specific examples of already deregulated or to be deregulated markets for electric power are discussed to illustrate this matter.

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1. Introduction

1.1 An efficient deregulation

A change in technology or a shift in its policy may lead a government toward deregulating industries that were considered until then to be natural monopolies or strategic in terms of national security. New technologies that have reduced the critical size of a generation unit, as well as a general trend toward economic liberalization, are pushing an increasing number of countries to deregulate their electric power industries. When choosing the path toward deregulation, the regulator must keep in mind the two criteria that the future deregulated market should meet in order to be efficient. It must first provide the decision-makers with the *information* they need to take decisions but also produce the *incentives* that will have them take the optimal ones.

In a perfect market, as defined in any handbook of microeconomics, it is the unique equilibrium price of the market that conveys information about marginal costs and marginal utilities and provides the appropriate incentives to the market participants to set their own marginal cost or utility in order to maximize the total social welfare.

A deregulated electric power market, with its three components, generation, transmission, and distribution, is not a perfect market. The transmission network creates externalities on the generation side if its value is not reflected in the prices paid to generators; constraints on the transmission lines create network externalities, as the actions of a generator might affect the ability of other generators to take similar actions. The simplest market mechanisms fail to produce a unique price that provides the market participants with the appropriate information about the capacity of the transmission network and incentives not to abuse this network. If a government is decided to deregulate its electric power industry, it seems reasonable that the market players should be prevented, through appropriate market rules, from excessively abusing the market imperfections.

One of the major focuses of the economic debate that the future deregulation has first initiated was about *finding means to process the information* and generate appropriate pricing of transmission that would internalize the externalities produced by the transmission network. We can observe two opposite trends in the methods that have been proposed, both acknowledging that generators and consumers know their own costs and utilities, and the operator of the transmission grid, or what is often called the Independent System Operator (ISO), has the information about the transmission capacity of the network. The first trend, illustrated by Hogan (1992) (Harvard University), advocates *centralizing information* about the generation cost and consumers' utility through bids submitted to an ISO that would calculate appropriate transactions and prices, the prices being different at every node of the network. At MIT, Ilic (1997a) favors *decentralizing information* about the transmission network by providing market participants with transmission costs and having them decide what transactions will take place. A number of other proposals offered compromises between these two extremes; Wu and Varaiya (1995) from Berkeley have advocated, for example, a market mechanism with multiple stages and different rules at every stage[1].

The underlying assumption behind all of these proposals is that the market participants are price takers and, therefore, that the pricing methods they advocate will produce automatically the appropriate incentives. It is this assumption that this thesis challenges. Its main message is that, if the industry is to be deregulated, transmission constraints can amplify dramatically the problems of market power and the regulator can design the transmission strategy in order to reduce this phenomenon.

1.2 Contributions and outline

This thesis can be divided into two main parts, each one conveying half of the message. In the first part it is shown how the physical laws on the transmission grid (chapter 2) and the associated financial instruments (chapter 3) can amplify market power and create market imperfections. The second part demonstrates how the rules that will govern transmission of electric power between generators and consumers can be chosen in order to reduce these imperfections (chapter 4) and discusses their implementation (chapter 5).

Chapter 2 introduces the problem by highlighting briefly, through a simple example, the need of different prices at different nodes of the network in order to internalize the externalities created by the transmission grid. It then shows with another simple example, as well as a more elaborated simulation of a 24-nodes system, how transmission constraints and loop flow can create geographically localized markets, relevant from an Antitrust point of view. Most importantly, these sub-markets might be relevant while still connected by non-constrained lines to the rest of the network. The market participants can have significant locational market power in these relevant sub-markets. In order to predict the type of behavior that is to be expected in these sub-markets, the thesis examines different types of oligopolistic models that could be used. It concludes that supply function competition, and Bertrand competition with increasing marginal costs or generation capacity constraints, describe more accurately than Cournot competition the short term strategic behavior of the market participants. This chapter finally finds that tacit collusion between the generators might be sustainable if a spot market with posted daily bids is created by the regulator.

Chapter 3 exposes some of the detrimental incentives that financial instruments might give to the market participants. It first explains the need for financial instruments to hedge against the volatility of transmission costs and to finance investments in new transmission lines. These types of financial instruments are known to potentially produce incentives to detrimental investments in the transmission grid (Bushnell et al., 1996). This chapter shows how they can also induce strategic bidding on the short term and sub-optimal investment in generation capacity on the long term. These problems of moral hazard are found to be more pronounced when the revenues yielded by these financial instruments depend on the real flows through the transmission network.

[1] See Ilic et al (1997b) for a comparative presentation of these three methods.

Chapter 4 shows how the physical and financial markets for transmission can be designed in order to reduce the imperfections highlighted in the two previous chapters. On the physical market for transmission, it is shown that when access to transmission can be guaranteed for a long term, and when the market participants do not have to make their transactions through a spot market, tacit collusion should not be sustainable. Concerning financial instruments, this chapter suggests that hedging instruments sold by an independent insurance agency are less susceptible to produce moral hazard than those distributed by an independent system operator. The latter should rather use the merchandising surplus, collected as a congestion rent, to fund the financial instruments for grid expansion in order to reduce the economic distortion due to economies of scale and the constraint of an equilibrated budget and. Finally, and most importantly, this chapter presents the result of a simulation that shows how an expansion policy for the transmission grid that relies on ex-ante characteristics of the market can be effective to reduce the general problem of locational market power introduced in chapter 2.

In fifth chapter, the implementation of the policy recommendations that were analytically found useful in chapter 4 is discussed. It first explains why other methods to reduce market power, as price caps and multiplication of ownership, have serious limitations for the electric power industry. The policy recommendations are then exposed and their implementation discussed. Specific examples of already deregulated or to be deregulated markets for electric power are given as an illustration.

In the conclusion, I will discuss how environmental constraints or the time gap between planning and executing a network expansion can reduce the credibility of a threat of network expansion and indicate why the use of FACTS technologies can help restore this credibility.

The remainder of the present chapter gives the definitions of physical and financial rights used in this thesis.

1.3 Definitions

We find in the literature too many distinct concepts when using the phrases “physical rights” and “financial rights," and when speaking about the transmission grid. We will try here to separate these concepts and to highlight some of their characteristics.

1.3.1 Physical rights

1.3.1.1 Definition of physical rights used in this thesis

To implement a power market, electric power must be injected into a transmission system, transmitted by it, and taken out (ejected). The **right and obligation** to implement these processes are referred to here as **physical injection, transmission and ejection rights**[2]**.** They match exactly, and in real time, flows into, through and out of the transmission grid.

1.3.1.2 Options on physical rights

We contrast this definition of physical rights with the same term, used in various discussions. “Physical rights” is sometimes used to mean short or long term contracts that give to their owner a certain priority (depending on whether they are firm or interruptible contracts) for acquiring physical injection, transmission, or ejection rights. We will refer to those contracts as “options on physical rights.” These options can be tradable among the market participants.

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[2] As an abbreviation for *Physical Right and Obligation* we use *Physical Right.*

1.3.1.3 Implicit or explicit physical rights?

Under certain of the proposed deregulation methods, physical rights can be defined explicitly and traded or distributed by an Independent System Operator (ISO) in such a way that no transaction of power can take place if it is not associated with corresponding physical rights. Therefore the allocation of physical rights must follow a feasibility rule that respects the constraints imposed by the grid. An example is the nodal prices model developed by Hogan (1992), in which an ISO mandates what every generator is to inject, i.e., distributes the injection rights. In other models, the market mechanisms might determine the transactions without dealing explicitly with physical rights, but these rights are always implicitly defined and associated to real flows, which are authorized by the ISO or agreed upon by all market participants. Even though the rights are not explicitly defined, they play a major role since the implicit rights still have to respect the feasibility rule.

1.3.2 Financial rights

Financial rights, as opposed to physical rights, are not an integral part of implementing power markets and do not give any right over or obligation to the physical flow of power. Rather, they are financial instruments designed artificially and sold or distributed to market participants or to investors in the grid by an ISO or by independent insurance agencies. The revenues they provide to their owners are usually linked to some of the characteristics of the market for power (basically prices and/or quantities).

As for physical rights, financial rights can be explicitly defined or implicitly defined. We will discuss this point later, when we introduce the "merchandising surplus" in section 3.1

2. Imperfections in the physical market

Combined cycle technologies, and other new technologies in the generation of electric power, have reduced the economies of scale in this sector, together with the critical size of a single generation unit, enabling the multiplication of generators and reducing their individual market power[3]. This phenomenon is expected to facilitate the emergence of a competitive generation market and is one of the major arguments in favor of deregulating the electric power industry. Without transmission constraints and losses, the market for generation would have a unique equilibrium price and the features of a classical perfect or oligopolistic market, and a reduction in the critical size of a generator should definitely improve the competitiveness of the market. Nevertheless, because of loop flow, transmission constraints, and other network externalities, the electric power market is unique and the impact of the transmission grid on the market power of the generators should be studied carefully and without prejudice.

The electricity market as seen by distributors and main loads can be conceptually separated into two distinct markets: The "market for generation" itself, and the "market for physical transmission rights" to transmit the energy bought in the first market from the seller to the buyer. Depending on the market structure, these two functions will be bundled or unbundled, but can always be separated, at least conceptually, in the analysis of any proposed market structure. It is necessary to understand the respective impacts of these two markets on the prices seen by the consumers and on the market power whose consequences distributors and loads might have to bear and that can be originated in each one of them, and must be treated accordingly. One of the major claims of this chapter is that while the size of the market participants tends to give them the power to influence the price of generation itself, their location tends to give them the power to influence the price of transmission, i.e., the price of physical rights. This phenomenon can produce geographically localized zones where individual generators can have significant market power, and raises new challenges to the ongoing deregulation; local oligopolies and tacit collusive behavior are only two examples of such challenges.

2.1 Introduction: The need for spatial differentiation

2.1.1 Nodal pricing

A unique uniform electricity price is unable to provide appropriate signals to the market participants because of the externalities produced by the transmission network. Schweppe et al. (1988) have shown in the context of a vertically integrated industry how it is possible to

[3] The market power of a generator is its ability to profitably maintain prices above the competitive level.

calculate a set of 'nodal prices', one for every node at the network, that would theoretically maximize the social welfare. The difference in prices between two nodes reflects the transmission costs, which are costs of losses on the transmission lines and opportunity costs due to congestion on some of these lines.

As a simple example, we can consider a three-node network without losses with three identical transmission lines, the maximum transmission capacity of every line being 5 units of power. We have on this network two generators, G1 and G2, with constant marginal costs of 1 and 2 units of costs respectively, and one load, L, with an inelastic demand of 10 units of power.

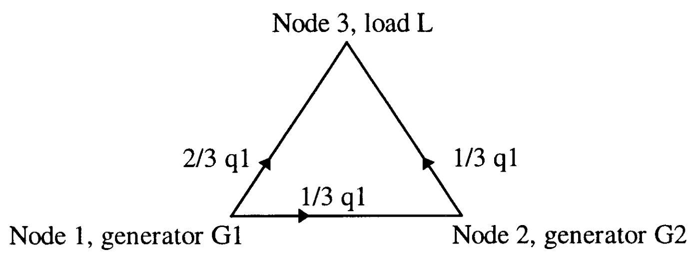

Figure 1: Nodal pricing

Because of loop flow, 2/3 of the output q1 of G1 will flow on line 1-3 and 1/3 will flow on lines 1-2 and 2-3. Therefore, generator G1 cannot satisfy alone the needs of load L because the line 1-3 would be operating outside its constraint. When generator G2 is also producing, 1/3 only of its output q2 will flow on line 1-2: substituting partially G2 to G1 will reduce the flow on this line enabling the system to work within its constraints. Minimizing the generation cost under the constraints

(1) $q1+q2=10$

and

(2) $2/3q1+1/3q2\leq 5$

gives the optimal physical dispatch:

(3) $q1=5$ and $q2=5$

The nodal prices P1, P2, and P3 at nodes 1, 2 and 3 respectively are the shadow prices of the system:

(4) $P1=1, P2=2, P3=3.$

It is interesting that the nodal prices 1 and 2 are equal to the marginal costs of the generators at these nodes. Moreover, the nodal price at node three is greater than the marginal cost of the most expansive generator: In order for the load to get 1 more unit of power, and because of loop flow, we must reduce the output of G1 by 1 and increase the output of G2 by 2. The marginal cost to the system is therefore 3 units of cost.

Hogan has proposed, in one of the paper that has the most influenced the economic debate in this field (Hogan, 1992), that this method should be used in the deregulated electric power market. The market participants were to reveal to an Independent System Operator (ISO) their cost and utility functions and this ISO would calculate the optimal transactions and the nodal prices.

2.1.2 *From uniform to nodal pricing*

One of the open questions concerning pricing for transmission system support at times of scarcity is related to the tradeoff between simplicity and accuracy in generating accurate price signals. The proposals range from uniform, to zonal and nodal pricing. Uniform pricing advocates pro rata shares of costs created by congestion by all system users (loads). It is simple but it does not reflect locational and temporal differences in system use, and, consequently, does not create appropriate incentives to ration the system adequately.

In contrast to this approach, stands the nodal pricing approach, that we have described in the last section, which requires extensive computation and measurements to differentiate the locational aspect of system use.

The idea of zonal pricing recognizes the different locational impact of various users, but advocates an aggregation of customers into "zones". All customers in the same zone pay the same price.

2.1.3 *An example*

The danger of zonal pricing is an oversimplification that would lead to serious inefficiencies. An example is given by the Rainbow Strawman Proposal, made by the Boston Edison Corporation to the New England Regional Transmission Group. This proposal advocates the creation of "constrained" and "non-constrained" zones where the loads of the constrained zones would split proportionally the out-of-merit generation cost occurring in their zone. Splitting the constraints' costs between the loads proportionally to their consumption is equivalent to saying that the nodal prices these loads are paying are equal. But if Hogan's nodal prices in the constrained area are not equal (and because of loop flow there is no reason for them to be equal), the Rainbow Strawman will send price signals that shift the system away from the economic optimum.

The proposal will work well in simple configurations such as the following:

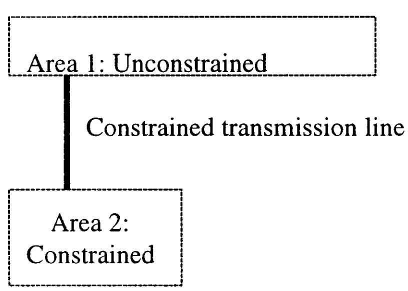

Figure 2: Zonal pricing, a simplification of nodal pricing

But in the following configuration, the prices paid by loads L1 and L2 should be different to make them take the optimal decisions (if they are sensitive to the price):

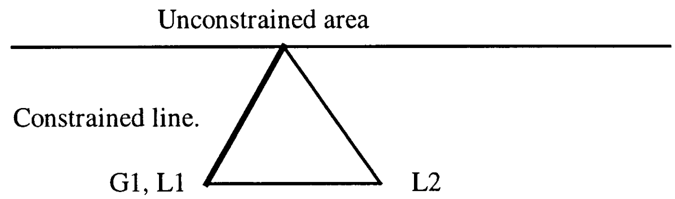

Figure 3: Zonal pricing can be an oversimplification

The boundary case is a constrained area completely separated from the unconstrained area, where all loads would be paying the same price for power.

In fact, the proposal assumes that there is a well-defined constrained interface and constrained area, and that there are no constraints *inside* this constrained area. This is not true, a priori, unless the zones are chosen adequately and differentiated and modified with the evolution of the market conditions

2.2 Locational market power exists

The nodal pricing proposal advocated by Hogan (1992) has been frequently criticized because it ignores the potential market power that the market participants can have in such a framework. Singh, Hao and Papalexopoulos (1997) show how, with location-dependent nodal spot pricing and transmission constraints, a non-discriminating auction mechanism creates opportunities for strategic behavior. Nevertheless, the problem of market power lies beyond the auction mechanism or the features of the nodal pricing model. More generally, in any market structure that tries to give rational economic signals to every market participant, i.e., a structure that recognizes spatial differentiation (section 2.1), generators in areas constrained by weak transmission lines do see their market power boosted because they are isolated, by the constraints, from the competition of other generators. This problem should not disappear, for example, in Berkeley's proposal (Wu et al., 1995) of multilateral markets where a few isolated generators in a constrained area will still have significant power in multilateral negotiations, or in any other method that recognizes spatial differentiation.

To illustrate this phenomenon, we use a simple model where two generators G1 and G2 and an aggregated load L are isolated from the rest of the network by a constrained line whose maximum capacity is K. P and λ are respectively the electricity prices in the constrained and unconstrained areas and $d(P)$ is the demand of the load L.

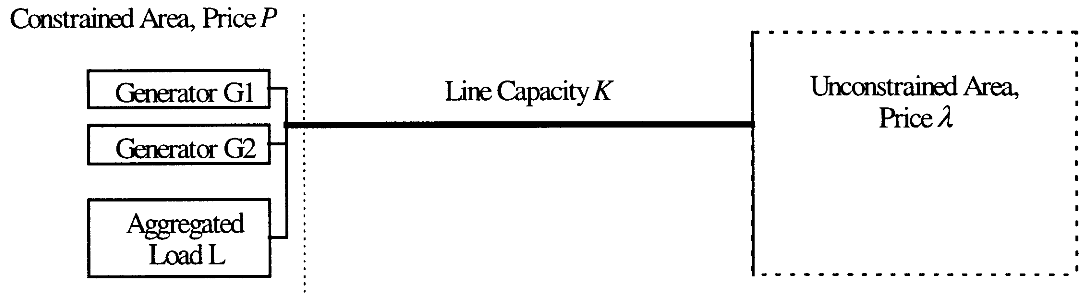

Figure 4. Market Power Due to Transmission Constraints

The market in the constrained area is similar to a duopoly with a competitive fringe where the fringe has a constant marginal cost λ and a maximum production capacity K. As long as the price P is above λ, the line is constrained and the generators G1 and G2 are facing a demand $d'(P)=d(P)-K$. They will act in this case as a perfect duopoly facing the new demand d', with full market power that this situation gives them.

Nevertheless, a constrained zone completely isolated by a constrained line is exceptional; more generally, the transmission lines are constrained because of loop flows and there might always be a path of non-constrained transmission lines between constrained and non-constrained generators. To find out whether transmission constraints could still induce local market power in this general scenario, we have simulated the realistic IEEE reliability system (IEEE, 1979) using a modified version of a software developed by Macan (1997). This system consists of 24 nodes, 38 transmission lines, 19 inelastic loads, and 14 generators with quadratic cost functions and finite generation constraints located at 10 nodes.

Using a nodal pricing method à la Hogan and assuming that the generators are communicating their cost functions[4] to a central Independent System Operator, the software calculates the socially optimal dispatch, the nodal prices at the generation nodes, and the profits of every generator. It is straightforward to conclude that in a competitive market the generators will maximize their profits by communicating their true cost functions. Nevertheless, the number of generators is finite and every one of them has the power to influence the nodal price and sometimes to raise its profits by cheating on its cost function. The goal of our simulation was to examine how transmission constraints can influence this power and whether they can raise it locally, producing sub-markets that are relevant from an Industrial Organization point of view[5].

[4] The cost function coefficients may be estimated on the base of price bids.

[5] As posed by G. Werden (1996), from the Antitrust Division of the US Department of Justice, a group of products and geographical areas constitute a relevant market when a monopolist could exercise significant market power over them, and significant market can be defined in terms of the price increase that a monopolist would impose. As an example, a price increase of five percent is typically used in the merger-antitrust context.

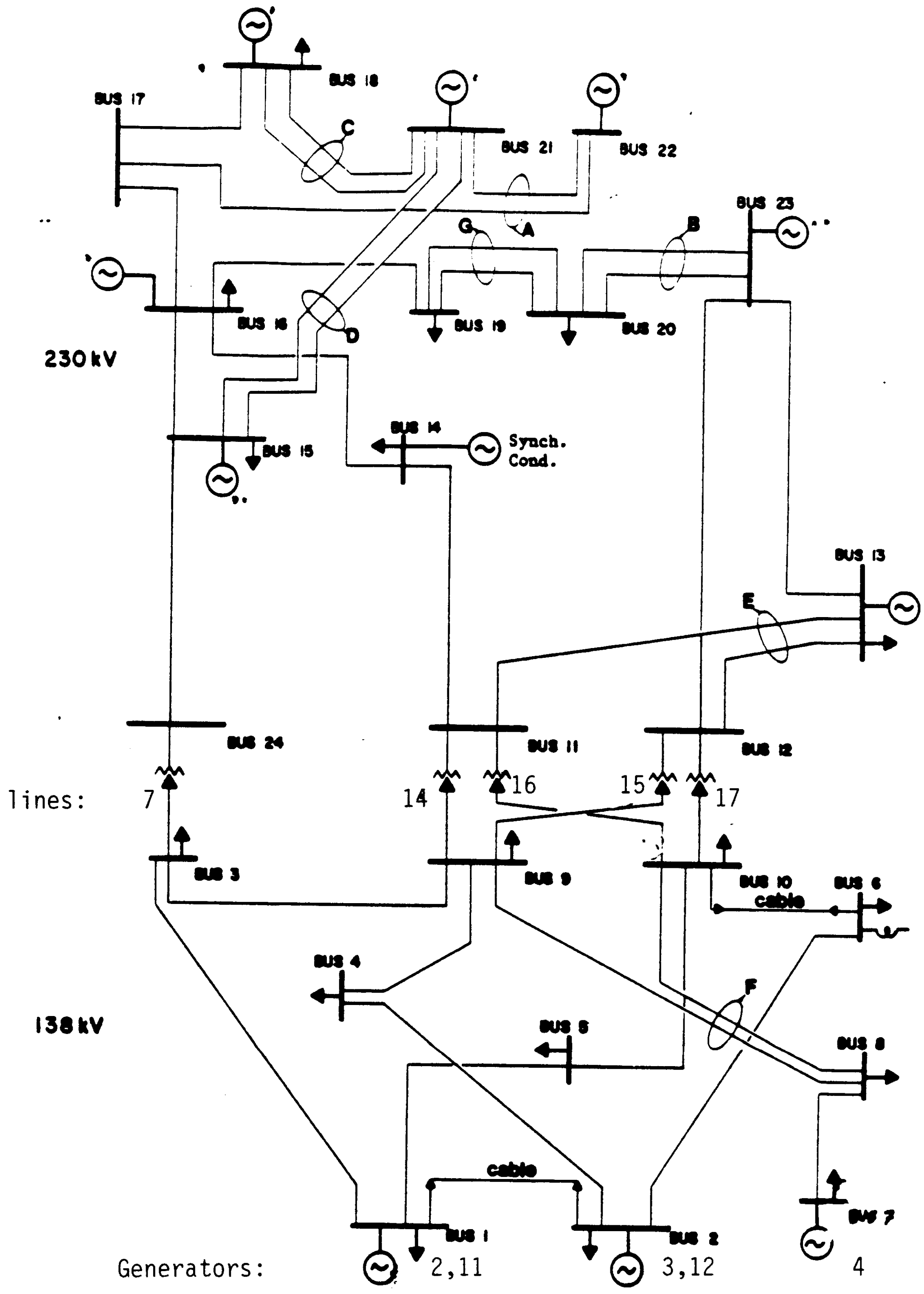

Figure 5: IEEE Network

Five transmission lines (lines 7 and 14 through 17), separating the network in two distinct sub-networks, can potentially be constrained while all other lines are operating far from their limits. We consider three different levels of demand. At the first level, only line 7 is constrained; at the second, lines 7 and 16 are constrained. At the third demand level, lines 7 and 17 are constrained while line 14 is operating so close to its limit that some generators can cause it to be constrained by changing their bids. For every demand level, we have raised by 10% the cost function processed by the ISO of every one of the fourteen generators, leaving the costs of the other thirteen unchanged, and observed which nodal prices where sensitive to which costs. This experiment has suggested that nodes 1, 2 and 7, where generators 2, 3, 11, 12, and 4 are located, could constitute a potentially relevant market.

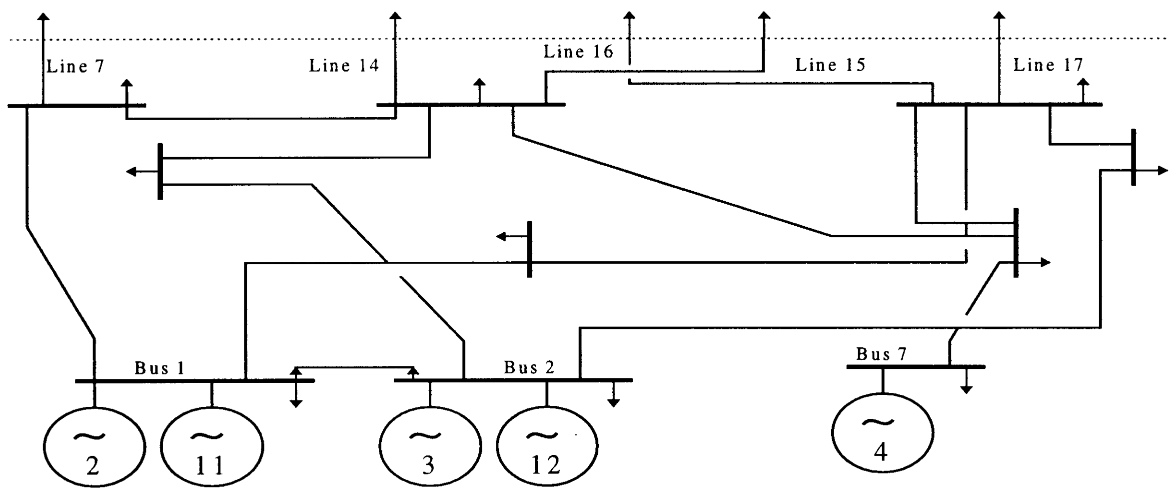

Figure 6. A Relevant Sub-Market of the IEEE 24-Bus Reliability System

To confirm this suggestion, we have raised by 10% the bids of these five generators together as a monopoly could do (cf. the definition of a relevant market), with (Table 1) and without (Table 2) transmission limits on the five critical transmission lines. The following two tables summarize the *increases* in prices and profits that this 10% increase in bidding has produced in the two cases.

Demand level	Lines that are constrained	PRICES Node 1	Node 2	Node 7	Ranges for other nodes	Aggregated profits at nodes 1, 2, and 7
1	**7**	5.7%	5.4%	4.9%	-1.3% to 3%	**+17%**
2	**7,16**	9.8%	9.7%	10.3%	-0.6% to 1.4%	**+26.3%**
3	**7,17,(14)6**	9.2%	9.3%	10%	-1.4% to 0.2%	**+18.5%**

Table 1. Changes in prices and profits with *transmission constraints*

[6] Line 14 becomes only constrained after the generators raise their price.

Demand level	Lines that are constrained	PRICES Node 1	Node 2	Node 7	Ranges for other nodes	Aggregated profits at nodes 1, 2, and 7
1	**none**	1.3%	0.7%	1.1%	0.5% to 1%	**+1%**
2	**none**	1.3%	1.2%	1.3%	0.8% to 0.9%	**+2%**
3	**none**	3.1%	3.2%	2.9%	2.3% to 2.6%	**+6.9%**

Table 2. Changes in prices and profits without *transmission constraints*

It is clear from these results that the generators that are at nodes 1, 2, and 7 constitute a relevant market for the three levels of demand, especially for levels 2 and 3. Moreover, it appears that it is the transmission constraints that are making this market relevant in the first and second levels of demand, since removing the transmission constraints dilutes the market power of these generators by putting them directly in competition with the other generators on the network. We will further note that their size is contributing to their market power in the third level of demand where they have significant market power in the absence of transmission constraints because the cheap generators that are competing with them are already working at their full capacity. *In all three levels,* locational *market power is created by the "market for physical transmission rights" because of the particular location of the relevant sub-market. In the third level of demand, the "market for generation" is raising the generators'* global *market power because of their size and cost functions.* It is of primary importance that, in the first and second levels of demand, respectively only one and two lines are constrained out of the five that separate the sub-market from the rest of the network, and that these constraints are raising the market power by an order of magnitude. This indicates that lines constrained by loop flows can produce sub-markets that are relevant markets from an economic point of view while these sub-markets are still connected by many other non-constrained transmission lines to the rest of the network. Locational market power created by transmission constraints, a classical problem in almost all network economies, is thus increased dramatically by loop flows, the specificity of electric power networks. Finally, it is interesting that the level of demand affects the "degree of relevance" of sub-markets; markets that are not relevant in off-peak periods could become relevant in peak periods and we have therefore to add the temporal scope to the geographical one when searching for relevant markets.

2.3 Oligopolistic Analysis

2.3.1 Oligopolistic Modeling

As we have seen in the last section, locational market power will exist because of loop flows and transmission constraints that produce geographically and temporally localized relevant markets. Moreover, global market power can also exist, transmission constraints put apart, because of the relative size of a competitor as shown by the experience of deregulation in the British electric power market (Wolfram, 1995). Therefore, one should not assume, a priori, that the market is perfect, but rather take the potential existence of market power into consideration in any form of proposed deregulation and try to limit this power. To do this, we will have to replace our traditional assumptions of a perfect market with a more realistic oligopolistic model.

The type of oligopolistic model that is adapted to study the type of oligopolistic competition depends on the future rules of the market that the regulator will choose. In a centralized market, where an ISO takes the bids of the generators and loads and decides what the physical dispatch will be, the type of competition is exogenous and depends on the bidding procedure. When the generators are bidding prices and the ISO deciding for quantities, the competition will be a Bertrand competition. When the generators are to bid their production levels as a function of the price, the equilibrium prices will then be given by the "supply function equilibrium" developed by Klemperer and Meyer (1989) and applied to the British power market by Green and Newberry (1992). The equilibrium price will then lie above those yielded by a Bertrand competition and beneath those given by a Cournot competition in the unlikely case where the generators are bidding quantities only.

In a decentralized market where the transactions are settled in bilateral and multilateral markets, the type of competition is endogenous and probably not unique[7]. One of the most classical oligopolistic models is the Cournot model where the firms compete by choosing the quantity they want to put on the market and an independent auctioneer sets the price that clears the market. Well adapted to study long-term competition and barriers for entry, Cournot competition models are useful in scenarios where the firms first commit themselves to a production capacity and compete next by choosing prices in a second period. This is based on the fact that in a two-periods game where rigid capacities are chosen in the first period, the competition by prices (Bertrand competition) in the second period yields the same results given by a one-period game where the strategic variable chosen by the firms is their output (Cournot competition) and the price is settled by an independent auctioneer (Kreps and Schneikman, 1983). Therefore, the Cournot competition model might be adapted to examine generation competition in a long term strategic interaction framework where the generators have to choose their generation capacity à la Cournot before competing à la Bertrand every day. Nevertheless, besides some specific cases (the oil market in certain periods of its history for example), competition by quantities is fairly unrealistic to analyze short-term competition. This is especially true in decentralized multilateral and bilateral electric power markets where firms will bid rarely for quantities only and where the central auctioneer that sets the price does not exist. One could argue in favor of using Cournot competition to determine what happens on a daily basis since it is supposed to give the expected output of a Bertrand competition in the "second period". Nevertheless, this rationale makes two very strong and unrealistic assumptions: The demand characteristics should be the same in the "second period" as those expected when the capacity choices were made. They should also be fairly stable in the very short term to enable us to use the long-term expected outcome (the outcome of the two-stage Cournot competition) and interpret what happens on an hourly basis. Therefore, this model seems unable to give valuable insights on the short-term (hourly, daily) competition in a generation market where demand is highly volatile and competition is primarily by price.

A more adapted alternative for short-term analysis is the classical Bertrand oligopolistic competition model where the strategic variables are the prices that each competing firm chooses to maximize its profit, considering as fixed the prices of its competitors. Under this model, the equilibrium price will be the marginal cost of production when the products are undifferentiated, the firms can serve all the demand they face at a constant marginal price, and the players are assumed to play once. This result, combined with the observation that the prices on the British electric power market are above marginal prices has sometimes been used to reject this competition model in favor of a Cournot competition (Oren, 1997). Nevertheless, Edgeworth (1897) has shown that, if no single firm can serve all the demand, the output of a Bertrand competition with production capacity constraints is no longer competitive and the equilibrium price can go above the marginal cost. As reported by Tirole (1988), this result is valid in the

[7] However, it might be affected by the rules adopted by the ISO to have the players respect the transmission constraints: Curtailment of output, surcharges for using constrained lines, etc.

more general context of price competition between firms with increasing marginal costs. It is due to the fact that at the competitive price, every firm has an incentive to raise its price, its competitors being on their supply curve and not willing to supply more to make up for the deficit in offer (as opposed to the situation with constant marginal cost). Even when the marginal prices are assumed to be constant, the electric power generators have generation constraints and no single one can always serve all the demand it faces. Therefore, the price competition model is not to be rejected but its results must be interpreted in the context of generation capacity constraints and increasing marginal costs.

While a Bertrand competition model could be used, the supply function model (Klemperer and Meyer, 1989; Green and Newberry, 1992), where generators bid both prices and quantities, can constitute a credible alternative. This is especially true in a highly decentralized market where the prices of the transaction are not public and where large customers are likely to obtain better prices than smaller ones. In a decentralized market, we are likely to observe a combination of Bertrand competition and supply function competition in the different geographic and temporal relevant sub-markets.

However, none of the models we discussed takes into consideration the repeated nature of the interactions between the players. When this interaction is periodic, and especially in a centralized scheme where the prices are public, one could observe inter-temporal Nash strategies where tacit collusion is enforced by retaliation threats.

2.3.2 Tacit collusion

Chamberlain (1929) suggested that within a framework of oligopolistic competition and homogenous good, market participants, because of the threat of price war, could sustain a monopoly price without explicit collusion. Friedman's Folk Theorem (1971) illustrates how tacit collusive behavior can appear in the context of an infinity of repeated basic games with price competition (Bertrand supergame). This theorem states that any average payoff vector that is better for all players than the Nash equilibrium payoff vector of the basic game can be sustained as the outcome of a perfect equilibrium. Under certain conditions, betting for example the monopoly price as long as all other players do the same, and coming back indefinitely to the Nash bet of the single stage game after any deviation, can be a Nash strategy in the framework of the inter-temporal infinitely repeated game. The electric power market seems, unfortunately, to constitute a credible candidate for tacit collusion.

To illustrate this claim, we will consider a model similar to that of Brock and Schneikman (1985) where N generators with a constant marginal cost c and a production capacity k are facing a demand q given by $q = a - p$. p is the price and a is a coefficient larger than c. The generators are competing by prices in an infinitely repeated game. In a one-shot game, the equilibrium would be a Bertrand-Nash equilibrium (BNE) of pure or mixed strategies[8]. In the repeated game, the generators can either choose to collude at the monopoly price or to proceed with a price war and stay at the BNE that yields the lowest possible price. At every stage of the repeated game, every generator chooses to collude by bidding the monopoly price and sharing the demand with the others, to defect by bidding a price that is slightly under the monopoly price and producing at its full capacity, or to play the one-stage Bertrand Nash strategy if he is expecting other generators to do the same. By using the results reported by Brock and Shneikman (1985), we can easily calculate the benefits that every generator will get at every period from colluding (function $C(N,k)$), defecting ($D(N,k)$) or staying at the BNE ($B(N,k)$).

---

[8] For $(a-c)/(N+1)<k<(a-c)/(N-1)$ there exists no pure strategy, i.e., the equilibrium bidding prices are random variables.

- For $k<(a-c)/2N$, the total capacity is under the monopoly capacity, the generators will always produce at full capacity and their individual profit is $C(N,k)=D(N,k)=B(N,k)=k(a-c-N.k)$.
- For $k>(a-c)/2N$,

  - the individual profit from collusion is the shared monopoly profit $(a-c)^2/4N$,

  - the profit from defection is $k(a-c)/2$ if $k<(a-c)/2$ and $(a-c)^2/4$ otherwise,

  - the profit in a BNE is $k.(a-c-N.k)$ for $k<(a-c)/(N+1)$, 0 for $k>(a-c)/(N-1)$ and $((a-c)-(N-1).k)^2/4$ otherwise[9].

In this Bertrand supergame, a possible trigger strategy for every generator is colluding while all other generators are colluding and playing infinitely the simple Bertrand Nash bid after observing the first defection.

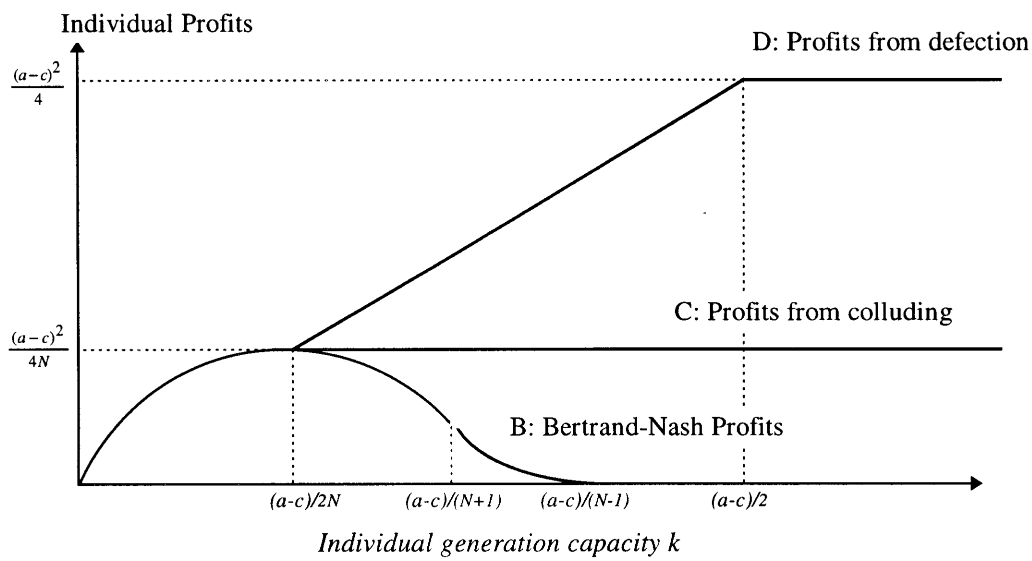

Figure 7: Individual Profits from Colluding, Defecting, or Staying at the One-Stage Equilibrium

Colluding will be a sustainable behavior when this strategy is a Nash strategy, i.e., when the profits from defecting in one period are smaller than the discounted future profits that a generator will loose by defecting, or, r being the discount rate and T the period between two interactions,

$$(5) \qquad D(N,k)-C(N,k) \leq \sum_{i=1}^{\infty}(C(N,k)-B(N,k)) \cdot \exp(-rTi)$$

[9] As we have mentioned earlier, it is the existence of generation capacity limits that enables the generators to sustain a price that is above the marginal cost in a one stage Bertrand competition.

$$D(N,k) - C(N,k) \leq \frac{C(N,k) - B(N,k)}{\exp(rT) - 1} \quad (6)$$

The trigger strategy is a Nash strategy when this inequality holds and collusion at the monopoly price would then be a sustainable equilibrium for the N generators. More sophisticated strategies can be imagined to make sure that an accidental deviation does not bring the system indefinitely to the single game Nash equilibrium, the key conditions remain however that no player should be able to make any benefit from defecting and the threat of price war must be credible.

Tacit collusion can appear in the framework of a Bertrand or a supply function competition (or even a Cournot competition) and its real danger lies in the Nash quality of its equilibrium that confers it stability since nobody has an incentive to cheat unlike in classical cartel behavior. Furthermore, tacit collusion does not necessitate the communication channels that cartelisation needs and will therefore rise more easily and be more difficult to prove and monitor by regulators.

Tacit collusion is rather an unusual phenomenon but a centralized framework where posted daily or hourly bids of generators are managed publicly by a central ISO seems to constitute a perfect framework for it to rise. Every market participant evaluates a tradeoff between the immediate benefit from a free riding behavior and the future losses from the competitive equilibrium. His decision will be a function of his discount rate between two consecutive interactions; this discount rate will be extremely low in a framework where power companies are bidding against each other every day (every half-hour in certain propositions).

Detection lags of price changes usually play an active role in hindering tacit collusion by raising the benefit from defecting and reducing the incentives to collude because collusion is based on the threat of retaliation and retaliation cannot occur before the detection of a deviation[10]. With posted bids, the prices and quantities supplied are known immediately and retaliation can take place with no delay.

Exceptional demand size encourages occasional free riding and hinders collusion; because electric power can hardly be stored, no exceptional quantities can be traded on a short-term market.

Forgiving trigger strategies might encourage free riding. The time lag between two interactions is so small that even if renegotiations are possible to restore a collusion after an occurrence of free riding, the renegotiation will not take place before the once-free-riding company gets hurt by the competitive behavior it caused and no temporal defection followed by renegotiation will take place.

Collusive behavior is usually very difficult to sustain in large systems because a very high number of market participants with different characteristics increases, for some of them, the incentives for defection[11] and any instability or irrational behavior spreads quickly to the whole system by making the collusive behavior sub-optimal. In the market for electric power, transmission constraints create geographical and temporal relevant sub-markets with reduced

[10] With a fair number of competitors, keeping the bids hidden and releasing minimal information about prices may encourage 'free riding' among generators and thus discourage collusion.

[11] See (Brock and Schneikman, 1985) for more details on the effect of the number of participants in Bertrand repeated game with capacity limits

numbers of generators, sub-markets that are separated from each other's direct influence and protected from any price collapse in another sub-market.

3. Imperfections in the financial markets

"When analyzing real time operations, there is a tendency to view the question of financial transmission rights as a non-issue. After all, financial transmission capacity rights don't affect economic dispatch, right? [...] That type of thinking, however, leads to erroneous conclusions" (Ilic at al, 1997b).

Financial rights, used for hedging against transmission cost or for funding the grid expansion, can create long term *and* short term detrimental incentives. This chapter reviews some of the known detrimental incentives that financial instruments might give to the market participants on the long term but shows also that they can also induce strategic bidding on the short term, producing therefore a sub-optimal physical dispatch. This is especially true when the revenues yielded by these financial instruments depend on the real flows through the transmission network.

3.1 Introduction: the merchandising surplus

3.1.1 Existence and redistribution

Whatever the dispatching rules are, when a physical dispatch is efficient in the short term, the congestion of the network produces a Merchandising Surplus (MS) which is a classical congestion rent. This surplus is either implicitly redistributed (e.g., Berkeley model (Wu et al, 1995), see Section 3.2.2.2), or it is recovered by an ISO and must be reallocated explicitly in some way. In the nodal prices proposal (Hogan, 1992), for example, the pricing mechanism generates a merchandising surplus equal to $(\sum_i -Pi.qi)$, where ***Pi*** is the nodal price and ***qi*** the power injected at node *i*, and this surplus is strictly positive if a network is congested. Of course, this merchandising surplus should not be allocated directly to the ISO because of the bad incentives that this ISO would then have to raise this surplus by imposing a sub-optimal dispatch. There are basically two proposed uses for this surplus, financing the capital cost of the grid or hedging the market participants against transmission price risk.

3.1.2 Equity problems

The major problem that a regulator will have to face when choosing how to redistribute this surplus remains a problem of equity. The redistribution of this surplus is a purely monetary allocation choice and does not affect the social welfare in the short term (Ilic et al., 1997a).[12] *Thus, there is no unique neither fair way to do it, unless we consider the impact of this allocation on the long-term efficiency, or the efficiency of the investments in generation, loads, and transmission capacity.* In the longer term, things are different, and allocation rules of the surplus can help shape the market structure and thus the welfare. (See sections 3.3.2, 3.4).

3.2 An overview of financial rights

3.2.1 Roles of financial rights

The existence of the merchandising surplus has promoted the introduction of financial rights in many of the proposed models for deregulating the power industry. The first introduction of the concept of financial right was partially motivated by a practical issue, redistributing a flow of money that the ISO should not keep for itself, to keep it away from temptation. Nevertheless, financial rights have an intrinsic value as potential policy instruments when designed carefully, and offered by the right institution, i.e., not exclusively the ISO. Financial instruments have basically two important potential roles to play in a deregulated market: hedging against the market risk and giving appropriate incentives to stimulate an efficient expansion of the transmission grid.

3.2.2 Types of financial rights

3.2.2.1 Explicit financial rights

Financial rights can take a multitude of shapes. Two important types of explicit financial rights that an ISO could distribute or sell are Link Based Rights and Transmission Congestion Contracts.

In the ***Link Based Rights*** (LBR) approach (Oren et al, 1995) the owner of an LBR receives a payment that compensates him for the difference of nodal prices between the two nodes of that link (the transmission cost) times the *real* flow on the line joining those two nodes. If the LBRs are allocated for all the transmission lines, the payments are equal to the surplus.

In the ***Transmission Congestion Contract*** approach (Hogan, 1992), the owner of a contract (between two nodes that are not necessarily directly linked) receives a payment equal to the difference in nodal prices times a *contractual* flow allocated ex-ante. If the allocated TCC constitute a feasible dispatch, it has been proved that the total payment is, *at the most,* equal to the merchandising surplus.

3.2.2.2 Implicit financial rights

However, financial rights, like physical rights, can be implicitly defined. In the Berkeley approach (Wu et al., 1995), for example, the curtailment made by the ISO between the first and the second period is in fact an implicit distribution of financial rights to the market participants. It gives every one of them a financial revenue, redistributing exactly the merchandising surplus. This revenue will depend on the way the curtailment is made (the financial right each one gets) and the market conditions (clearing prices in the two phases and physical dispatch) (Ilic et al. 1997a). More generally, every market mechanism that optimizes the short term physical dispatch

[12] Unless it is done in a way that gives incentives to deteriorate it: When this surplus is distributed to market participants via financial rights, the market participants might in some cases have an incentive to adopt a strategic behavior that could cause the physical dispatch to deviate from the efficient one in the short term. See Section 3.3.2.

will have a degree of freedom to redistribute in some way (implicit or explicit financial rights) the surplus that will inevitably be generated.

3.3 Hedging instruments

3.3.1 Overview

The market participants may need to protect themselves against fluctuations in transmission cost. This can be done with contracts from insurance agencies, but it raises the problem of how these agencies will get the information they need about the market; this problem is of course contingent to the proposed market model. It has also been proposed that the ISO could distribute (part of) the MS as financial rights to hedge those that "deserve" it (Hogan, 1992). Nevertheless, the types of financial rights that have been proposed to do this task (e.g., TCCs) hedge against the fluctuation of the congestion on the market and the associated costs. They offer a second order insurance as opposed to insurance that can be used against the fluctuation of the price of power such as the contracts for differences. These types of rights not only reduce the variance of transmission cost but also the expected price and are more re-distributive than hedging instruments; and once again, there is no unique or even fair way to do this distribution in a non-discriminatory way. Finally, and most importantly, it is frequently assumed that financial hedging instruments will have no impact on the physical dispatch of power, i.e., the allocation of physical rights. Nevertheless, many of the proposed hedging instruments (e.g., long term rigid contracts) do have a serious impact on physical dispatch and thus on social welfare. An example is given by the Rainbow Strawman proposal (Younes et al., 1997a, p18). More generally, any financial hedging instrument whose revenue depends on the physical decisions of its owner (e.g., an option to buy at a given price), and is not tradable, is expected to have an influence on the physical decisions of its owners. On the other hand, the existence of a market for those rights or even the formal dissociation between the financial revenue of such rights and the short term physical decisions of their owners (e.g., TCCs) do not guarantee that those rights have no influence on the social welfare. Hedging instruments might give detrimental incentives to their owners and encourage deviation from the optimal physical dispatch in the short term or detrimental investments in the long term. In both cases, hedging instruments could have a negative impact on the total welfare.

3.3.2 (Bad) incentives given by hedging instruments

We will show in the following sections that when those rights are allocated at no cost by an ISO in order to redistribute the merchandising surplus, they can produce short or long term strategic behavior and have a detrimental impact on social welfare[13]. Depending on who gets the surplus, and on the allocation procedure of financial rights, two categories of potential inefficiencies could result: *Long term inefficiency* caused by detrimental investments in the grid, the generation or the loads, and *short term inefficiency* due to the strategic behavior of the market participants during the bidding process. We will use as an example the case of the nodal prices model and two different financial instruments: TCCs and LBRs.

[13] Making the players pay for the hedging instruments they need can have a positive impact on the design of those rights, as will be discussed in Section 4.2.1.1.

3.3.2.1 Threats to short term efficiency

Hedging instruments whose revenues depend on the real flows on the network might induce sub-optimal equilibrium.

On a market for electric power, where players are price takers, and where an appropriate process makes the system converge to the socially optimal equilibrium in the absence of financial rights, one of the generators wants to insure himself against the fluctuation of congestion on the network. He pays PF to obtain a financial right F that will give him, when the market clears, a revenue that will depend on the price he is paid, p, and on his output q'. q' is, a priori, different from q^*, the output he would have chosen if he had not bought F. Let this revenue be $RF(p,q')$.

The cost function of this player being C, his total revenue is:

(7) $$TR(F,q') = -C(q') + p \cdot q' + RF(p,q') - PF$$

The player will choose the output $q'(F)$ that maximizes TR; thus,

(8) $$\frac{\partial C(q')}{\partial q} = p + \frac{\partial RF(p,q')}{\partial q}$$

If the revenue yielded by the financial right does not depend on the real injection ($\frac{\partial RF}{\partial q}(Pi, q'(F))$ **= 0), the financial right will have no effect on the physical dispatch and q'=q*. Otherwise, the physical dispatch will be affected** since the output $q'(F)$ will shift away from the socially optimal output q^*.

We will examine as an illustration the case of the nodal prices model and the ownership of Link Based Rights (**LBRs**). In the *short run*, a generator owning a LBR has incentives to adopt a strategic behavior while bidding, even if he is a price taker, and thus, he might shift the dispatch to a sub-optimal one. The following provides an example.

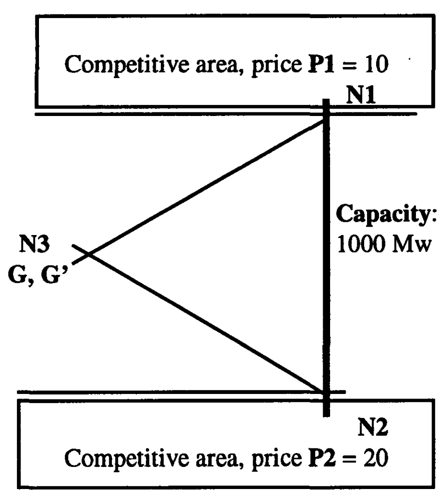

Figure 8: Financial instruments can affect short-term physical dispatch

Two competitive areas at nodes N1 and N2 are linked directly by a constrained transmission line and indirectly through node N3. The two areas are large enough so that the prices in these areas, $P1$ and $P2$, are not affected by node N3, and stay respectively at 10 and 20 units of cost. The ejections of power out of nodes N1 and N2 are $q1$ and $q2$.

G' is a competitive aggregation of unconstrained generators at node N3. Its output $q3'$ depends only on the price at node 3, P3. G is a single generator that owns the LBR from node 3 to node 2, it output is $q3$.

Moreover, the three transmission lines have the same impedance.

It is easy to see that the price at node 3 will be $P3 = 15$ units of cost regardless of the generating costs are at node 3. Moreover, $P1$, $P2$, $P3$ and $q3'$ are independent of $q3$ and

(9) $2/3.q1 + 1/3.(q3+q3') = 1000$

gives

(10) $$\frac{\partial q1}{\partial q3} = -1/2$$

The generator G is a price taker and he chooses his output $q3$ (by making the appropriate bid) in order to maximize his revenue R. C being his cost function:

(11) $R = P3.q3 - C(q3) + (P2-P3).(1/3.q1 + 2/3.(q3+q3'))$

Thus, using (10),

(12) $$P3 - \frac{\partial C(q3)}{\partial q3} + (P2-P3)*(1/2) = 0.$$

His marginal cost $\frac{\partial C(q3)}{\partial q3}$ *is different from the price P3 and his output q3 is shifted away from the socially optimal output because of the LBR.*

Concerning **TCCs**, some of the short term inefficiencies have been highlighted by Oren (Oren, 1997) who showed that if the competition among generators is a Cournot competition and the nodal prices are defined ex-post, the generators will capture the value of the TCCs by implicit collusion and, by doing so, might shift the dispatch toward a sub-optimal one. Even if the competition is not a Cournot one, section 2.3.2 has shown that collusion might appear.

3.3.2.2 Threats to long term efficiency

Redistributing the merchandising surplus via financial rights can also produce long-term inefficiencies, even if we assume that some regulation is preventing the generators from strategic bidding and from creating short-term inefficiency.

An owner of a transmission right between two nodes with similar prices may have an incentive to invest in a generator, which raises the transmission price between the two nodes and thus increases his revenue from this right. His aggregated revenue might rise even if the generator itself is losing money.

The following example gives an illustration:

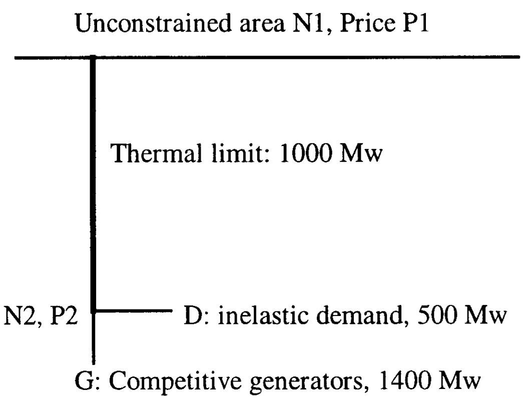

Figure 9: Detrimental incentives for investment in generation capacity

The node *N2* is not constrained and *P2* = *P1*. If the owner of one of the generators in *G* also owns the transmission right from node 2 to node 1, **TCC or LBR**, he might have an incentive to build a new generating capacity of 200 MW, constraining the node 2 area in generation, constraining the transmission, making *P2* go under *P1* and increasing the revenue generated by the transmission right. The revenue generated by the transmission right might exceed the losses of his generating capacity, at the expenses of the owners of the remaining generation capacity at node 2.

3.4 Financial instruments to fund the grid

The expansion and enhancement of the grid must be funded and the merchandising surplus is generated by the congestion of the grid. It seems natural to finance this expansion by that surplus. Besides, when the expansion has to be made in a decentralized way, the surplus must be broken down into financial rights that investors in the grid will receive as (part of) their remuneration. When the merchandising surplus is not enough to finance this expansion, other sources and other financial rights must be found and designed to finance this expansion. More importantly, these rights should be designed in a fashion that gives the appropriate incentives to ensure an efficient expansion of the grid.

As with the financial rights for hedging, one major concern should be the detrimental incentives that the allocation of this surplus gives to the investors in the grid. If the investment is centralized, the investor will have a clear incentive to create congestion and to raise the surplus if the investor can appropriate the congestion rents. When investment in the grid is opened to private initiative, the incentives given will depend on the allocation rule among the investors. Stoft and Bushnell (1996) have proposed an elegant but impractical rule that should give the right incentives to the investors, but no convincing general allocation mechanism has been drafted so far for TCCs or LBRs.

Moreover, similar to what was described in the last sections, another bad incentive given to the rights owners will be to encourage detrimental investments in the generation side. Also, the owner of an ill designed financial right[14] will have an incentive to collude with neighboring generators or load in order to maximize their joint profits, producing again a short term sub-optimal dispatch. The two examples given for hedging instruments are still valid in the case of financial instruments to fund the grid, in which case we could observe the same kind of detrimental behavior.

[14] See section 4.2.1.2 for definition

4. Using the transmission strategy to reduce market imperfections

The goal of this chapter is to demonstrate that the transmission strategy the regulator will choose can be used to reduce some of the imperfections that we have highlighted in the last chapters. Both the rules on the physical market and the characteristics of the financial instruments that will be designed can be very useful if chosen appropriately. One of the main messages is that the incentives given by both physical and financial markets are correlated and that one market can be designed to insure the efficiency of the other. We will see in this chapter how long term contracts between generators, loads, and the transmission owners can hinder tacit collusion on the physical market. It is also shown why the merchandising surplus should be used to fund the expansion of the grid rather than to subsidize hedging instruments, these hedging instruments being more efficient from a social welfare point of view if sold by an independent insurance agency. Most importantly, it is also shown how a financial instrument to fund the expansion of the grid, if well designed, can help reduce locational market power on the physical market.

4.1 Hindering tacit collusion on the physical market

4.1.1 Long term contracts hinder tacit collusion

Many factors affect the sustainability of tacit collusion: Detection lags of changes in prices, asymmetries in cost structures between market participants, number of players, etc.

Most notably, the frequency of the interactions plays an essential role. As suggested by Tirole (1988) and confirmed by Brock and Shneikman (1985) in the case where there exist production capacity constraints, the discount rate between two interactions is an essential stability factor of collusive behavior because every participant evaluates a tradeoff between immediate benefits and the future cost of non-cooperation, and a larger discount rate always diminishes the value of future retaliation. One way to hinder collusion is therefore to change the discount factor between two interactions by changing the frequency of these interactions. Making the interaction less frequent raises this rate and might prevent collusion. It seems reasonable that while bidding every half hour could discourage free-riding and make collusion sustainable, *long term contracts (5 to 20 years) imply a very large discount rate that might discourage, in turn, collusive behavior.*

To illustrate this claim, we consider again the infinitely repeated game between N generators developed in section 2.3.2. It is clear from (6) that the period T between two interactions will determine whether the trigger strategy is a Nash strategy and whether we are likely to observe tacit collusion at the monopoly price. Moreover, it is possible to choose T in order to make the trigger strategy not sustainable for all values of k and N for which this strategy yields a different outcome than the one stage equilibrium. This period, T_{min}, should satisfy:

$$\textit{(13)} \qquad \frac{1}{\exp(rT_{\min})-1} \leq \min_{k,N \backslash k > \frac{a-c}{2N}} \frac{D(N,k)-C(N,k)}{C(N,k)-B(N,k)}$$

This minimum, for N fixed, is met for

$$(14) \qquad k = \frac{a-c}{N},$$

Then,

$$(15) \qquad \min_{k,N \backslash k > \frac{a-c}{2N}} \frac{D(N,k)-C(N,k)}{C(N,k)-B(N,k)} = \min_{N} \frac{N}{N-1} = 1$$

Implying

$$(16) \qquad T_{\min} \geq \frac{\ln(2)}{r}$$

In other words, for any number of generators of any size facing any linear demand, and for a discount rate of 10%, contracts for delivery of electric power during 7 years or more should always help hinder collusive behavior. Of course this strong result gives only an order of magnitude, and more realistic data should be collected to analyze this phenomenon and determine *Tmin* with non linear demand, increasing and asymmetric marginal cost functions and a potential "supply function" competition scheme.

4.1.2 Collusion issues to be investigated

In order to prevent collusion, other factors have to be investigated and their impact on collusive behavior clarified.

Dynamics of collusion: How does collusive behavior evolve in a deregulated power industry? Under what circumstances could a system that has deviated from collusive behavior return to the previous equilibrium? Understanding these mechanisms will enable us to design an appropriate structure that makes collusive behavior non-sustainable.

Amalgamation of prices in constrained zones and dynamics of global collusion: It would be interesting to use the techniques introduced by Simon (Simon et al., 1961) to amalgamate the collusion level in every constrained zone. It will enable us to study how the global level of collusion between weakly linked constrained zones could converge to an equilibrium in the long term. A better knowledge of these mechanisms could provide us with some strategies to prevent this phenomenon.

4.2 Incentives given by the financial markets

4.2.1 Sources of financial rights

4.2.1.1 Funding the expansion of the transmission network

The merchandising surplus, existent in all the proposed market mechanisms that attempt an optimal dispatch explicitly or implicitly, could be used to (partially) fund the capital cost for expanding the grid (Lecinq et al., 1997). The main advantage would be to reduce the fixed and variable charges of transmission that have to be collected from the market participants. We know from economic theory that those charges will inevitably produce distortions in the social welfare if they do not correspond to variable costs. Using the merchandising surplus to allocate financial rights to hedge against congestion pricing would, at best, lead to a pure monetary allocation that does not affect the global efficiency of the system or the social welfare. Using it to finance the grid will help reduce the necessary variable charges that have to be taxed to system users and, by doing so, reduce the economic distortion and increase the social welfare.

It will be interesting to investigate how the additional charges, that will be collected if the merchandising surplus does not yield enough revenue, must be designed to minimize their impact on the social welfare. It is known that if the "optimal" solution includes necessarily fixed charges, this solution is impractical for occasional wheeling transactions. It might be useful to have the ISO propose different choices of charges (variable vs. fixed) to the market participants from which every one will pick the type that will suit him the most.

Furthermore, one should not forget that the grid already exists and the major part of its cost has already been depreciated[15]. Could the dynamic nature of the expansion of the grid allow us to finance completely the capital cost of the *marginal expansion* from the surplus produced by the *whole grid*? The answer will depend on the celerity of the expansion, the chosen depreciation time frame and on the real lifetime of a transmission line. In any case, if this is possible, we will have found a source of financing totally the expansion of the grid in a socially optimal way.

4.2.1.2 Who should sell or distribute hedging instruments?

We will designate as **ill designed** those financial rights that give detrimental incentives, from a total welfare point of view, to their owner - or induce "Moral Hazard". We have seen in section 3.3.2 that TCCs and LBRs can be, in certain conditions, considered as ill designed financial rights.

"Insurance Agencies Will Not Sell Ill Designed Rights." This provocative statement is true under the strict assumptions that the insurance companies have enough information to know the expected value of the rights they are selling, the insurance market is competitive, and the market participants maximize their expected profits, i.e., they are neutral to risk.

In this framework, the two first assumptions indicate that the price of the rights will be equal to their expected value. The third assumption makes the market participant choose to buy this right by comparing his expected revenue when he buys the right and when he do not. The expected value of the right being offset by its price, he must compare his direct *physical market* benefits from the actions he will take in the two cases. Therefore, he will not buy an ill designed right that will make him deviate from the simple behavior of maximizing the benefits from the real transactions of power.

[15] The remaining fixed cost is presently being recovered through a fixed Regional Network Service (RNS).

The example introduced in 3.3.2.1 illustrates this claim. If the financial right F is sold by an insurance company that have enough information to know the expected values of the rights it is selling, and if the insurance market is competitive, it is clear that price PF of F is equal to $E(RF(p,q'))$, the expected value of the revenue yielded by F.

The expected revenue of this player is therefore:

(17) $E(TR(F)) = -E(C(q'(F)) + p.q'i(F))$

Supposing that the revenue of F depends on the output (it is therefore ill designed as shown in 3.3.2.1) and therefore $q' \neq q^*$, q^* being the optimal choice of the player in the absence of financial rights, we have:

(18) $-C(q') + p \cdot (q') < -C(q^*) + p \cdot (q^*)$,

therefore,

(19) $E(-C(q') + p \cdot (q')) < E(-C(q^*) + p \cdot (q^*))$,

or,

(20) $E(TR(F)) < E(TR(0))$.

In other words, the insurance contracted by the player i ex-ante (before the market clears) leads him to a sub-optimal output ex-post (when his price is known) and the expected outcome of this insurance is offset by its price. Therefore, the player will not take an insurance whose outcome depends on his real injection, and the insurance companies should not propose such an insurance.

Of course this is an extreme case and the problem of moral hazard exists because firms are never perfectly neutral to risk (or we would not need hedging instruments) and the information that an insurance company obtains about the market can always be manipulated. Besides, the capacity of a player without market power (a player who cannot influence nodal prices) to influence the flows is not straightforward. Nevertheless, we have seen that when the ISO is distributing rather than selling financial rights, the problem of moral hazard exists even under the assumptions we have made. Moreover, it seems intuitive, but has not yet been proven here, that for a degree of aversion to risk, the market participants might choose the financial instrument that produces the lesser degree of moral hazard. Besides, private insurance agencies are not bound by any budget constraint and have the technical and financial ability to propose much more sophisticated financial instruments to market participants that feel the need to hedge their revenue against fluctuations of *transmission cost*. We should note that, in this context, those financial instruments can be combined with other financial instruments to hedge against fluctuations of the *price of electricity* itself.

To summarize, the financial rights allocated at no cost to the market participants can produce bad incentives in both the short and long terms. Allowing market participants to buy financial instruments from insurance agencies can be much more efficient because the market participants internalize the expected revenues of those contracts by paying their price. It can be shown, for example, that no transmission contract that shifts ex-post the real dispatch from the optimal one will be bought (under certain assumptions). Another argument is that the instruments proposed by an insurance agency can be much more sophisticated and efficient than those an ISO could propose.

4.2.2 *Allocation of financial rights*

4.2.2.1 Is a decentralized investment in the grid feasible? (or the virtue of ex-ante remuneration)

The regulator will choose between a centralized and a decentralized investment scheme. The decentralized scenario should yield more efficient results than the centralized scenario because of the assumed virtues of concurrence. Nevertheless, to achieve this, we will have to design the financial rights and mechanisms to remunerate private investors that will internalize the network externalities without falling in the same kind of inefficiencies we described for hedging financial rights. This is not an easy task, but one possible approach would be to design financial instruments that yield a revenue that is a function of the characteristics of the market ex-ante and of the proposed project; and not of the conditions ex-post as it has been proposed until now, e.g., TCCs or LBRs, because of the detrimental incentives (moral hazard) that the latter could give to the investor.

Another approach would be to allow more than one investor to participate in building one line in a competitive way to resolve the problem of economies of scale and natural monopoly. Some work has been done in this direction (Braman) but the proposed model induces only a second-best solution because of the obligation given to the merchandising surplus to finance completely the expansion and this approach might not be better than a centralized investment by an ISO. Further research should investigate optimal solutions that use fixed and variable charges for transmission to provide a balanced budget for an optimal level of investment.

4.2.2.2 Grid expansion strategies for reducing locational market power (or the virtue of ex-ante remuneration, (2))

Hindering collusion is not sufficient to ensure a competitive market. As we have seen in section 2.3.2, even a simple Bertrand competition is likely to give-non competitive outcomes in the relevant sub-markets. A more global strategy is needed to eliminate, or at least decrease, the locational market power created on the physical market by congestion. Price caps and the multiplication of ownership might certainly be useful but have the side effects and limitations discussed in the conclusion. A more natural strategy would be to eliminate the cause of locational market power, i.e., transmission congestion, via a network expansion, or, even better, via the threat of network expansion. An expansion policy for the grid that takes into consideration the *used* market power in relevant sub-markets (e.g., via the prices that generators ask for) could constitute a credible threat against the use of market power. The credibility of the threat seems to be linked to the use of ex-ante characteristics of the market to remunerate the investors. For example, an expansion strategy that would yield the appropriate financial revenues to link two nodes whose electricity prices are sufficiently different *when* the investment is decided, and not *after* the line is built, could discourage generators at the expensive node from abusing their market power. By not raising their prices too much, they will stay separated from the unconstrained area and benefit from the modest rents that this strategy gives them[16].

To illustrate how a grid expansion policy that is a function of ex-ante conditions on the market can reduce the market power of the market participants, we have made a second simulation on the IEEE reliability system. Using the same software as in section 2.2, we are able

[16] Nevertheless, because of environmental considerations, new lines cannot always be built and this impossibility reduces the credibility of the threat. Investment in Flexible AC Transmission Systems (FACTS) devices could help reestablish this credibility.

to estimate the optimal expansion for the lines 7 and 14 through 17 under the peak load pricing method (Lecinq and Ilic, 1997; Macan, 1997)[17]. This capacity is a function of the costs of expansion, the demand functions, and, most importantly, the bids that the generators are making. It is noteworthy that in this model the generators are giving their bids before the expansion of the line is decided; i.e., the expansion policy of the grid depends on ex-ante characteristics of the market and behavior of the market participants. To analyze how the expansion can affect the market power, we have added a fourth demand level, greater than the former three. Furthermore, the original capacities of the five critical lines were set to their optimal values determined by the peak load pricing method when all the generators are bidding their real cost function in the four demand levels. We have then made the generators that are at nodes 1, 2 and 7 (that we have shown to form a relevant market) raise all together their bids by 10% in the four demand levels. This was done in the two scenarios where we allow or not further expansion of the transmission lines 7 and 14 through 17. The following two tables summarize the increases in prices and profits that this 10% increase in bidding has produced in the two cases.

Demand	PRICES				Ranges of profits	Total Aggregated
level	Node 1	Node 2	Node 7	Ranges for other nodes	at nodes 1, 2, 7	**profits**
1	1.4%	0.9%	1.6%	1.2% to 0.6%	0% to 2.9%	
2	3.3%	3.4%	2.6%	-0.2% to 1.7%	0% to 8.4%	**+ 21%**
3	10.2%	10.0%	10.1%	-0.9% to 0.1%	24.5% to 45.1%	
4	10.8%	10.6%	9.5%	-1.3% to 1%	19% to 32.3%	

Table 3. Changes In Prices And Profits When Expansion Is Not Allowed.

Demand	PRICES				Ranges of profits	Total Aggregated
level	Node 1	Node 2	Node 7	Ranges for other nodes	at nodes 1, 2, 7	**profits**
1	1.4%	1.1%	1.8%	0.5% to 1.8%	0% to 3.6%	
2	1.4%	1.5%	1.2%	0.5% to 1.2%	0% to 2.6%	**+1%**
3	3.3%	3.1%	3.1%	3.3% to 3.7%	6.3% to 10.7%	
4	-0.4%	-0.5%	0.3%	1.2% to 3.2%	-3.2% to -0.3%	

Table 4: Changes In Prices And Profits When Expansion Is Allowed.

When colluding together and raising their bids by 10%, and when the transmission capacity is fixed to its "optimal" value, the five generators at nodes 1, 2, and 7 are able to raise their cumulated profits by 21%. If we allow the transmission lines to expand accordingly to the bids of these generators, the same increase in bidding raises the cumulated profits by less than 1%, some of the generators being worse off. The studied sub-market can no longer be qualified as relevant, individual locational market power is seriously weakened and cartelisation is not sustainable. It is noteworthy that, in these conditions, non-competitive bids are therefore unlikely to be observed, as is an *effective* expansion of the grid. The *threat* of a transmission grid

[17] In the peak load pricing method, the expansion of the transmission lines and the nodal prices are calculated to maximize the total social welfare taking into consideration the generation price and the consumers surplus (as in Hogan's nodal pricing approach (1992)) as well as the capital cost of the grid expansion (as distinct from the Hogan approach). It is interesting that the nodal prices given by the peak load pricing are the same as those the Hogan nodal pricing calculations would give when the line capacities are set at the optimal values given by the peak load pricing method.

expansion is sufficient to remove the market power of the generators and alter the relevant character of the sub-market formed at nodes 1, 2 and 7.

4.2.2.3 Transitional period

As we have seen, on the short term, the distribution of the merchandising surplus via financial rights, if well designed, will only be a financial allocation without an impact on social welfare. In a transition period, we could use it to reduce the stranded cost of the old generators by distributing these financial rights to those generators. This can be justified by the fact that those generators have contributed to the construction of the existing grid and that they could be entitled, at least in a transition period, to whatever revenues this grid is generating, and giving them those revenues will not affect the overall efficiency. We will nevertheless be scarifying the benefits from using this surplus to finance the expansion of the grid. We have to compare the relative size of this surplus and of the stranded costs to see if it would be worthwhile to make the necessary political efforts to implement such a strategy.

5. Policy Analysis

5.1 Classical solutions to fight market power

As shown in this thesis, locational market power in general, and tacit collusive behavior in particular, threaten seriously the social welfare in the future deregulated power industry and must be treated as such when designing a regulatory framework for this deregulation.

The problems of global and locational market power have frequently been evoked in recent economic literature and sometimes used to offer counter-examples in the debate over the deregulation of the electric power industry. However, they have rarely been directly taken into consideration in the different general proposals that have been made so far for deregulating this industry. It is often thought that these problems can be treated independently from the general framework of the future market rules. As reported by Joskow (1996), two methods are usually proposed to reduce market power. They consist in imposing price caps or multiplying the ownership of the generators.

However, imposing price caps does not eliminate the market power but reduces its expression. When significant market power does exist, the prices will remain at the maximum authorized by the caps and the regulator will be virtually setting himself the transaction prices in peak periods by setting the maximum price cap. Such a practice can lead us closer to mandatory pricing than to true competition during these period and gives a very high discretionary power to the regulator. Moreover, high prices during peak periods can be a useful and legitimate economic signal to build marginal generation capacity needed for reliability. It will be very difficult for the regulator to make the difference between the abuse of locational market power in peak period and very high but legitimate prices, useful to reimburse the capital cost of the marginal production units.

On the other hand, multiplying ownership is a useful solution to reduce the global market power that utilities might have because of their total size, independently of transmission constraints. Nevertheless, it might not help reducing locational market power created by transmission constraints since some of the local and temporal relevant markets may not be sufficiently large to enable this multiplication. Multiplying artificially the number of firms can be detrimental to the social welfare as shown by Baumol (1982) in his theory of contestable markets. Furthermore, as shown by Brock and Shneikman (1985), on a market where market players with production capacity constraints are playing an infinitely repeated price competition game (or Bertrand supergames), increasing the number of firms has a non monotonic and thus ambiguous effect on collusion because raising the number of firms first encourages collusion by raising the losses incurred during a price war before hindering collusion by raising the relative profits of a defector.

5.2 Policy recommendations advocated by this thesis

It is my opinion that the problems raised by locational market power and its corollary, tacit collusion, cannot be resolved using artificial tools that ignore the specificities of this market. The solution should rather be an integral part of any proposal that pretends to produce an efficient market. This thesis has shown how long term contracts can help hinder tacit collusive behavior by encouraging free riding. It has also shown how, more generally, locational market power can be decreased through an expansion policy of the transmission grid that depends on the ex-ante behavior of the market participants, and other characteristics of the market, and that would expand the weak links when locational market power is abused. It has shown why such an expansion policy can produce the appropriate threats against the market participants, decreasing drastically their market power, without necessarily producing any real expansion of the transmission grid. Furthermore, this thesis suggests that an expansion policy that relies on ex-ante characteristics of the market can also help prevent detrimental strategic behavior of investors in the grid and in generation capacity. It is also recommended that the merchandising surplus should finance partially this strategy, while the financial hedging instruments must rather be designed and sold by insurance agencies independently of the system operator in order to minimize their impact on short term physical markets.

5.3 Implementation of the policy recommendation

The practical implementation of the majority of the recommendations seems feasible. A long-term market, competing with the spot market, exists already in UK and in the majority of the other deregulated electric power markets. If it is true that such a market is excluded from the purest approach to nodal pricing, in practice, even California, the market that will probably be the closest in its approach to nodal pricing, is very likely to allow long term contracts between producers and consumers[18]. As for who should design and sell the hedging instruments, forbidding the ISO to distribute TCCs or other types of hedging instruments should not be problematic as this is only a proposal that has been incorporated in the first approaches to nodal pricing by Hogan (1992) and that was never implemented. The merchandising surplus that was to be distributed using these instruments can be usefully and easily used to fund partially the cost of the transmission grid. It is instead recommended to have an insurance agency, a bank of any profit maximizing firm (the producers for example) do this job. This is the way hedging instruments are sold in any classical market and it will be implemented automatically as a consequence of forbidding the ISO to distribute hedging instrument.

The implementation of an expansion strategy for the transmission grid that would yield credible threats to those abusing their market power could be, in some situations, more difficult. The ultimate degree of deregulation would be achieved when the investments in the transmission network are done in an uncoordinated way by independent investors owning the lines they build and earning benefits from operating these lines. In that case, the remuneration of this investor depends only on the ex-post congestion of the network (e.g., Transmission Congestion Contracts). An investment that would reduce congestion and eliminate the abuse of market power might not yield enough revenues to the investors and the threat of such an investment would not be credible. Nevertheless, there are very few proposed methods that could send appropriate signals for investment in transmission and there are even fewer methods that can do it for decentralized investors. The most elaborated one, proposed by Bushnell and Stoft (1996),

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[18] As confirmed by several utilities delegates at the 18^{th} IAEE conference (Sep. 97, San Francisco)

rely on Transmission Congestion Contracts that would be distributed to the investors following to a feasibility rule. This proposal would yield correct incentives to the investors under restrictive conditions. However, when these conditions are not met, market participants might find it profitable to make alterations in the transmission grid that are detrimental to the system.

Most likely, the expansion of the transmission grid will be undertaken by an independent, but regulated, centralized operator or by those that are benefiting directly from the transmission network: Utilities and distribution companies. In England and Wales for example, the transmission is controlled, managed, and its expansions are planned by the National Grid Company (NGC). The NGC is jointly owned by the regional distribution companies though recently these companies have considered divesting their shares in NGC and making it an independent company. Nevertheless, NGC remains tightly regulated and it is required to facilitate competition and meet user's reasonable requests for connection to the system (Green, 1997). Implementing an expansion strategy similar to that recommended in this report is relatively easy and could be done through the regulations binding this company. Specifying, through these regulations, that the NGC have to build new lines when locational market power is abused would give to the threat of expansion the needed credibility. In the future deregulated California market, the transmission lines are owned by the Utilities and the ISO may have no financial interest in any transmission facility. Under a proposal submitted by California's three largest investor-owned electric utilities to the Federal Energy Regulatory Commission, the transmission owners would have an obligation to build transmission facilities the ISO decides are needed for economy or reliability (Burkhart, 1997). Implementing the expansion strategy proposed here in the California market will only require the ISO to have a transparent policy for expansion of the network that would specify that such an expansion will take place when locational market power is abused. Finally a very interesting case is New Zealand, where the system is very close to the spot pricing method and Trans Power, a state owned utility is responsible for operating the transmission system and for planning expansions. System expansions are justified if the difference in prices with and without a line equals the cost of the line (Green, 1997). This system might very well yield appropriate and credible threats against abuses of market power that would raise some nodal prices and justify new investments. Nevertheless, the market-based rule used by the industry is that investment should only be done if a coalition of users is willing to pay for it. The problems of free riding could alter the credibility of the threat.

6. Conclusion: Limitations and future research

We have seen how an expansion strategy that yields appropriate threats can reduce locational market power. Defining explicitly such an expansion policy must be the next objective of further research. This policy must meet two goals. (1) It should first induce, ex-ante, credible threats against the abuses of market power. (2) It must also produce, ex-post, a transmission network that has the appropriate dimensions. Moreover, it must also acknowledge the technical, environmental, and financial constraints.

In order to achieve the second goal, the threats of over-building the network must be dissuasive enough so that it has only to be rarely executed. However, due to technical constraints, the time needed to build a new line might be significant enough to make it worthwhile for a market participant to raise the market prices even if a new line will be build, reducing therefore the dissuasive power of the threat. Moreover, environmental constraints could make it unlikely to build new transmission lines on certain locations, reducing the credibility of the threat of expansion.

It seems that FACTS devices might be used to restore the credibility and the dissuasive power of the threat because their installation can be less time and capital consuming and more environmentally friendly than building physical transmission lines.

Funding the expansion strategy can also be a serious concern since no threat is credible, and no needed transmission capacity can be built when the needed funds are not available. The transmission costs paid by the market participants, or at least their expected value, must be sufficient to cover the capital cost of the grid and to remunerate the investors. If there is, as many authors agree, economies of scale in the transmission of electric power, pricing at the marginal cost will not yield enough revenues to cover the costs and some additional charges must be paid in order to equilibrate the budget. These charges ought to be chosen in a way that minimizes the economic distortions that they create. A good candidate would be to use a method similar to the voluntary price discrimination used by the insurance companies. Different combinations of fixed and variable charges from which they would have to choose can be proposed to the market participants.

Finally, once the problems of credibility and funding resolved, one still have to determine how the investment decisions will be taken, who will execute them, how would he be paid for them (as distinct from how to get the money to pay him), and who will own the physical lines. When the regulator decides that a centralized and regulated body (e.g., an ISO) will own and develop the network, designing an expansion strategy that has the characteristics described above can be (relatively) easy since the regulations that bind this body will give it the power to make his threats credible. Nevertheless, if the regulator chooses to go a step further and allow decentralized investments in the transmission network, an independent and unregulated investor would not execute a project unless he is expecting benefits. If the remuneration of this investor depends only on the ex-post congestion of the network, the threat of investment will not be credible. Future research should try to find a mechanism that would create a credible threat of individual investors over-building the network when market power is abused, while producing, ex-post, a well designed but competitively built network. This is definitely one of the most challenging goals to be achieved in this field.

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